The State of New Hampshire

DEPARTMENT OF ENVIRONMENTAL SERVICES

Thomas S. Burack, Commissioner

August 15, 2008

Thomas S. Burack, Chairman
New Hampshire Site Evaluation Committee
c/o New Hampshire Department of Environmental Services
29 Hazen Drive, PO Box 95
Concord, NH 03302-0095

RE: State Agency Final Decision
Tennessee Gas Pipeline Company – Concord Lateral Expansion Project
SEC Docket No. 2008-02

Dear Chairman Burack:

In accordance with RSA 162-H:6 VI, the New Hampshire Department of Environmental Services, Air Resources Division (DES) is required to make and submit to the New Hampshire Site Evaluation Committee (NHSEC) a final decision on the part of the Tennessee Gas Pipeline, Concord Lateral Expansion Project (Tennessee Gas Pipeline) application as it pertains to air emissions.

DES has made a final decision to grant a Temporary Permit to Tennessee Gas Pipeline. Attached please find a copy of the Permit.

A copy of this letter and the final Temporary Permit will be forwarded to each NHSEC member and the applicant. If you have any questions on this matter, please contact me at (603) 271-2630 or via e-mail at gary.milbury@des.nh.gov.

Sincerely,

Gary Milbury, Jr.

Gary Milbury, Jr.
New Construction/Planning Manager
Air Resources Division

Attachment: Final Temporary Permit TP-B-0544

Cc: NHSEC Members
Mr. William B. Cope – Tennessee Gas Pipeline
Ms. Trinh Tran – Eastern Pipelines Environmental
Ms. Tricia Beazley – Tetra Tech EC, Inc.

DES Web site: **www.des.nh.gov**
P.O. Box 95, 29 Hazen Drive, Concord, New Hampshire 03302-0095
Telephone: (603) 271-1370 • Fax: (603) 271-1381 • TDD A...

The State of New Hampshire
DEPARTMENT OF ENVIRONMENTAL SERVICES

Thomas S. Burack, Commissioner

August 15, 2008

Mr. William G. Cope
Vice President - Operations
Tennessee Gas Pipeline Company
1001 Louisiana Street
Houston, Texas 77002

Re: Temporary Permit TP-B-0544
One Compressor Turbine and One Emergency Generator
Tennessee Gas Pipeline Company
Concord Expansion Compressor Station
Mammoth Rd., Pelham, New Hampshire
Facility Identification #3301191266, Application #08-0023

Dear Mr. Cope:

The New Hampshire Department of Environmental Services hereby issues the enclosed permit in accordance with the New Hampshire Code of Administrative Rules Env-A 100 *et seq.*, *New Hampshire Rules Governing the Control of Air Pollution.*

Enclosed please find a questionnaire distributed by our Public Information and Permitting Unit. We are constantly trying to improve our permit processing and your feedback is greatly appreciated. If you have any questions, please contact Muriel Lajoie of the Air Resources Division, Permitting and Environmental Health Bureau at (603) 271-2822 or via e-mail at muriel.lajoie@des.nh.gov

Sincerely,

Robert R. Scott
Director
Air Resources Division

rrs/vhd
Enclosures: TP-B-05644 and Application Review Summary
By certified mail # 7006 3450 0001 6018 5505

cc: Ida McDonnell, USEPA, Region I
Town of Pelham
Town of Windham
Trinh Tran, Eastern Pipelines Env.
Tricia Beazley, Tetra Tech EC, Inc.

State of New Hampshire
Department of Environmental Services
Air Resources Division

Temporary Permit

Permit No: TP-B-0544
Date Issued: August 15, 2008

This certifies that:

Tennessee Gas Pipeline Company
1001 Louisiana Street
Houston, Texas 77002

has been granted a Temporary Permit for:

One Compressor Turbine and One Emergency Generator

at the following Facility and location:

Concord Expansion Compressor Station
Mammoth Road
Pelham, New Hampshire 03076

Facility ID No: **3301191266**
Application No: **08-0023**, received January 31, 2008 – Temporary Permit

which includes devices that emit air pollutants into the ambient air as set forth in the permit application referenced above which was filed with the New Hampshire Department of Environmental Services, Air Resources Division (Division) in accordance with RSA 125-C of the New Hampshire Laws. Request for permit renewal is due to the Division at least 90 days prior to expiration of this permit and must be accompanied by the appropriate permit application forms.

This permit is valid upon issuance and expires on **February 28, 2010.**

Director
Air Resources Division

Abbreviations and Acronyms

AAL	Ambient Air Limit
acf	actual cubic foot
ags	above ground surface
ASTM	American Society of Testing and Materials
Btu	British thermal units
CAS	Chemical Abstracts Service
cfm	cubic feet per minute
CFR	Code of Federal Regulations
CO	Carbon Monoxide
DER	Discrete Emission Reduction
DES	New Hampshire Department of Environmental Services
Env-A	New Hampshire Code of Administrative Rules – Air Resources Division
ERC	Emission Reduction Credit
ft	foot or feet
ft3	cubic feet
gal	gallon
HAP	Hazardous Air Pollutant
hp	horsepower
hr	hour
kW	kilowatt
lb	pound
LPG	Liquified Petroleum Gas
MM	million
MSDS	Material Safety Data Sheet
MW	megawatt
NAAQS	National Ambient Air Quality Standard
NG	Natural Gas
NOx	Oxides of Nitrogen
NSPS	New Source Performance Standard
PM10	Particulate Matter < 10 microns
ppm	parts per million
ppmdv	parts per million dry volume
psi	pounds per square inch
RACT	Reasonably Available Control Technology
RSA	Revised Statutes Annotated
RTAP	Regulated Toxic Air Pollutant
scf	standard cubic foot
SO2	Sulfur Dioxide
TSP	Total Suspended Particulate
tpy	tons per consecutive 12-month period
USEPA	United States Environmental Protection Agency
VOC	Volatile Organic Compound

I. Facility Description

The purpose of the Facility is to maintain pressure in the natural gas pipeline, through the use of a centrifugal compressor driven by a natural gas-fired turbine. Compressor Station 270B1 is part of the Concord Expansion Project to support growth needs in NH.

II. Emission Unit Identification

This permit covers the devices identified in Table 1:

Table 1 - Emission Unit Identification

Emission Unit ID	Device Identification	Manufacturer Model Number Serial Number	Installation Date	Maximum Design Capacity and Fuel Type(s)[1]
EU01	Compressor Turbine #1	Solar Centaur 50-6200LS TBD	2008	58.4 MMBtu/hr Natural gas – equivalent to 56,000 scf/hr @ 40 degrees Fahrenheit.
EU02	Emergency Generator	TBD TBD TBD	2008	4.68 MMBtu/hr Natural gas – equivalent to 4,489 scf/hr @ 40 degrees Fahrenheit.

III. Stack Criteria

A. The following devices at the Facility shall have an exhaust stack that discharges vertically, without obstruction, and meet the criteria in Table 2:

Table 2 - Stack Criteria

Stack Number	Emission Unit or Pollution Control Equipment ID	Minimum Height (feet above ground surface)	Maximum Exit Diameter (feet)
1	EU01	55	6

B. Stack criteria described in Table 2 may be changed without prior approval from the Division provided that:

1. An air quality impact analysis is performed either by the Facility or the Division (if requested by the Facility in writing) in accordance with Env-A 606, *Air Pollution Dispersion Modeling Impact Analysis Requirements*, and the "Guidance and Procedure for Performing Air Quality Impact Modeling in New Hampshire," and
2. The analysis demonstrates that emissions from the modified stack will continue to comply with all applicable emission limitations and ambient air limits.

C. All air modeling data and analyses shall be kept on file at the Facility for review by the Division upon request.

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[1] The hourly fuel rates presented in Table 1 are set assuming a high heating value (HHV) of 1,042.5 Btu/scf for natural gas.

IV. Operating and Emission Limitations

The Owner or Operator shall be subject to the operating and emission limitations identified in Table 3:

Table 3 - Operating and Emission Limitations

Item #	Requirement[2]	Applicable Emission Unit	Regulatory Basis
1	*Standards of Performance for Stationary Combustion Turbines* The compressor turbine shall comply with the following emissions limitations: a. NOx concentration not to exceed 25 ppmdv corrected to 15 percent O_2.	EU01	40 CFR 60.4320, Table 1 (Subpart KKKK)
2	*Emergency Generator* The emergency generator shall comply with the following emissions limitations: a. NOx concentration not to exceed 160 ppmdv corrected to 15 percent O_2. b. CO concentration not to exceed 540 ppmdv corrected to 15 percent O_2[3]. c. VOC concentration not to exceed 86 ppmdv corrected to 15 percent O_2	EU02	40 CFR 60.4233(e), Table 1 (Subpart JJJJ)
3	*Visible Emission Standard for Fuel Burning Devices Installed After May 13, 1970* The average opacity from fuel burning devices installed after May 13, 1970 shall not exceed 20 percent for any continuous 6-minute period.[4]	EU01 & EU02	Env-A 2002.02
4	*Activities Exempt from Visible Emission Standards* The average opacity shall be allowed to be in excess of those standards specified in Env-A 2002.02 for one period of 6 continuous minutes in any 60 minute period during startup, shutdown or malfunction.	EU01 & EU02	Env-A 2002.04(c)

[2] The Facility does not have the potential to emit the criteria pollutants NOx, SO_2, CO, PM_{10}, VOCs or Hazardous Air Pollutants (HAPs, as defined in Section 112 of the 1990 Clean Air Act Amendments) at levels greater than the major source thresholds for these pollutants. Therefore, the Facility is a true minor source for NOx, SO_2, CO, PM_{10}, VOCs and HAPs.

[3] Stationary SI ICE greater than 100 hp manufactured prior to January 1, 2011 that were certified to the certification emission standards in 40 CFR 1048 may comply with the carbon monoxide (CO) standard for which the engine was certified.

[4] Compliance with visible emission limitations shall be determined using 40 CFR 60, Appendix A, Method 9, upon request by the Division.

Table 3 - Operating and Emission Limitations			
Item #	**Requirement[2]**	**Applicable Emission Unit**	**Regulatory Basis**
5	*Particulate Emission Standards for Fuel Burning Devices Installed on or After January 1, 1985* The particulate matter emissions from fuel burning devices installed on or after January 1, 1985 shall not exceed 0.30 lb/MMBtu.	EU01 & EU02	Env-A 2002.08
6	*Maximum Sulfur Content Allowable in Gaseous Fuels* Gaseous fuel shall contain no more than 15 grains of sulfur per 100 cubic feet of gas at standard temperature and pressure.[5]	EU01 & EU02	Env-A 1605.01
7	*Emergency Generator* Each emergency generator shall only operate: a. As a mechanical or electrical power source when the primary power source for the Facility has been lost during an emergency such as a power outage; or b. During normal maintenance and testing as recommended by the manufacturer.	EU02	Env-A 1211.02(o)
8	*Emergency Generator* a. If the engine is maintained according to the manufacturer's emission-related written instructions, keep records of conducted maintenance to demonstrate compliance or; b. If the engine is not maintained according to the manufacturer's emission-related instructions, demonstrate compliance in accordance with Table 4, Item 3.	EU02	40 CFR 60.4243(b)(1) (Subpart JJJJ)
9	*Emergency Generator* The emergency generator may operate up to 50 hours per year in non-emergency situations[6], but those 50 hours are counted towards the 100 hour limit of operation during any consecutive 12-month period for maintenance checks and readiness testing and total operation shall be limited to 500 hours of operation during any consecutive 12-month period.	EU02	Env-A 1211.01(j)(1) and 40 CFR 60.4243(d) (Subpart JJJJ)

[5] This condition has been streamlined to cover both state and federal air regulations. Compliance the 15 gr/100 scf limit for gaseous fuels will ensure compliance with the 0.060 lb/ SO_2/MMBtu limit found in 40 CFR 60, *Subpart KKKK – Standards of Performance for Stationary Combustion Turbines.*

[6] The 50 hours per year for non-emergency situations cannot be used for peak shaving or to generate income for a Facility to supply power to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

V. Monitoring and Testing Requirements

The Owner or Operator is subject to the monitoring and testing requirements as contained in Table 4:

Table 4 - Monitoring and Testing Requirements

Item #	Parameter	Method of Compliance	Frequency	Applicable Unit	Regulatory Basis
1	To Be Determined	When conditions warrant, the Division may require the Owner or Operator to conduct stack testing in accordance with USEPA or other Division approved methods.	Upon request by the Division	Facility Wide	RSA 125-C:6 XI
2	Sulfur Content of Gaseous Fuels	Conduct testing to determine the sulfur content in grains of sulfur per 100 cubic feet of gaseous fuels by: a. conducting testing in accordance with appropriate ASTM test methods, or; b. maintaining a current, valid purchase contract or tariff sheet for the natural gas, specifying that the maximum total sulfur content for the fuel is in compliance with the sulfur content limitation provisions found in Table 3, Item 6.	Once Annually	Facility Wide	40 CFR 60.4360 and 40 CFR 60.4365 (Subpart KKKK) and Env-A 806.03(a)
3	Oxides of Nitrogen (NOx), Carbon Monoxide (CO) and Volatile Organic Compounds (VOC)	If the Emergency Generator *__is not__* maintained according to the manufacturer's emission-related instructions, the Facility must conduct periodic performance tests in accordance with 40 CFR 60.4244(a) through (f).	Within one year of engine startup and every 8760 hours of operation or 3 years elapsed whichever comes first.	EU02	40 cfr 60.4243 (a)(2)(ii)
4	Oxides of Nitrogen (NOx)	Compliance testing shall be planned and carried out in accordance with the following schedule: a. A pre-test protocol shall be submitted to the Division at least 30 days prior to the commencement of testing; b. The Owner or Operator and any contractor retained by the Owner or Operator to conduct the test shall meet with a Division representative at least 15 days prior to the test date to finalize the details of the testing; and c. A test report shall be submitted to the Division within 60 days after the completion of testing.	Within 60 days from startup of the device for the compressor turbine; within one year from startup of the device for the emergency generator	EU01 & EU02	Env-A 802

Table 4 - Monitoring and Testing Requirements					
Item #	**Parameter**	**Method of Compliance**	**Frequency**	**Applicable Unit**	**Regulatory Basis**
5	Oxides of Nitrogen (NOx)	Conduct periodic performance tests in accordance with 40 CFR 60.4400.	Once per year, no more than 14 months from previous test	EU01	40 CFR 60.4340 (Subpart KKKK)
6	Oxides of Nitrogen (NOx)	If the NO_X emission result from the performance test in Table 4 Item 4, is: a. less than or equal to 75 percent of the NO_X emission limit in Table 3, Item 1, the Facility may reduce the frequency of subsequent performance tests to once every 2 years (no more than 26 calendar months following the previous performance test); b. greater than 75 percent of the NO_X emission limit for the turbine, you must resume annual performance tests.	Annually, unless result is less than or equal to 75 percent of the NOx emission limit; then every two years	EU01	40 CFR 60.4340 (Subpart KKKK)
7	Oxides of Nitrogen (NOx)	The following test methods, or Division approved alternatives, shall be used: a. Method 20, 40 CFR 60 Appendix A to determine NO_x emissions in parts per million; b. Method 19, 40 CFR 60 Appendix A to determine the NO_x emissions rate in lb/MMBtu; and c. Method 3 or 3A, 40 CFR 60 Appendix A and molecular weight, to determine CO_2, O_2, and excess air on a dry basis.	During compliance testing	EU01	Env-A 802

VI. Recordkeeping Requirements

The Owner or Operator shall be subject to the recordkeeping requirements identified in Table 5:

Table 5 - Recordkeeping Requirements				
Item #	**Requirement**	**Duration/ Frequency**	**Applicable Unit**	**Regulatory Basis**
1	<u>*Record Retention and Availability*</u> Keep the required records on file. These records shall be available for review by the Division upon request.	Retain for a minimum of 5 years	Facility Wide	Env-A 902

Table 5 - Recordkeeping Requirements				
Item #	**Requirement**	**Duration/ Frequency**	**Applicable Unit**	**Regulatory Basis**
2	*General Recordkeeping Requirements for Combustion Devices* Maintain the following records of fuel characteristics and utilization for the fuel used in the combustion devices: a. Type (e.g. natural gas) and amount of fuel burned in each device, or type and amount of fuel burned in multiple devices and hours of operation of each device to be used to apportion fuel use between the multiple devices; b. Hours of operation of each emergency generator.	Monthly	EU01 & EU02	Env-A 903.03
3	*Gaseous Fuel Recordkeeping Requirements* Maintain one of the following: a. Sulfur content as percent sulfur by weight or in grains per 100 cubic feet of fuel; b. Documentation that the fuel source is from a utility pipeline; or c. Documentation that the fuel meets state sulfur limits.	For each delivery of gaseous fuel to the Facility or whenever there is a change in fuel supplier but at least annually	Facility Wide	Env-A 903.03
4	*General NO_x Recordkeeping Requirements* If the actual annual NO_x emissions from the Facility are greater than or equal to 10 tpy, then record the following information: a. Identification of each fuel burning device; b. Operating schedule during the high ozone season (June 1 through August 31) for each fuel burning device identified in Item 4.a., above, including: 1. Typical hours of operation per day; 2. Typical days of operation per calendar month; 3. Number of weeks of operation; 4. Type and amount of each fuel burned; 5. Heat input rate in MMBtu/hr; 6. Actual NOx emissions for the calendar year and a typical high ozone day during that calendar year; and 7. Emission factors and the origin of the emission factors used to calculate the NOx emissions.	Maintain Current Data	EU01 & EU02	Env-A 905.02

VII. Reporting Requirements

The Owner or Operator shall be subject to the reporting requirements identified in Table 6 below. All emissions data submitted to the Division shall be available to the public. Claims of confidentiality for any other information required to be submitted to the Division pursuant to this permit shall be made at the time of submission in accordance with Env-A 103, *Claims of Confidentiality*.

Table 6 - Reporting Requirements				
Item #	**Requirement**	**Frequency**	**Applicable Emission Unit**	**Regulatory Basis**
1	*Annual Emissions Report* Submit an annual emissions report which shall include the following information: a. Actual calendar year emissions from each emission unit of NO_x, CO, SO_2, TSP, VOCs and HAPs; b. The methods used in calculating such emissions in accordance with Env-A 705.02, *Determination of Actual Emissions for Use in Calculating Emission-Based Fees*; and c. All information recorded in accordance with Table 5, Items 2 and 3.	Annually (no later than April 15th of the following year)	EU01 & EU02	Env-A 907.01
3	*NO_x Emission Statements Reporting Requirements* If the actual annual NO_x emissions for the Facility are greater than or equal to 10 tpy, then include the following information with the annual emission report: a. A breakdown of NO_x emissions reported pursuant to Table 6, Item 1 by month; and b. All data recorded in accordance with Table 5, Item 4.	Annually (no later than April 15th of the following year)	EU01 & EU02	Env-A 909
4	*Permit Deviation Reporting Requirements* Report permit deviations that cause excess emissions in accordance with Condition VIII.B.	Within 24 hours of discovery of excess emission	EU01 & EU02	Env-A 911.04(b)(1)
5	*Emission Based Fees* Pay emission-based fees in accordance with Condition X.	Annually (no later than April 15th of the following year)	EU01 & EU02	Env-A 700

VIII. Permit Deviation Reporting Requirements

A. Env-A 101, *Definitions*:

1. A *permit deviation* is any occurrence that results in an excursion from any emission limitation, operating condition, or work practice standard as specified in either a Title V permit, state permit to operate, temporary permit or general state permit issued by the Division.
2. An *excess emission* is an air emission rate that exceeds any applicable emission limitation.

B. Env-A 911.04(b)(1), *Reporting Requirements*: In the event of a permit deviation that causes excess emissions, notify the Division of the permit deviation and excess emissions by telephone (603-271-1370), fax (603-271-7053) or e-mail (pdeviations@des.state.nh.us), within 24 hours of discovery of the permit deviation, unless it is a Saturday, Sunday, or state or federal legal holiday, in which event, the Division shall be notified on the next day which is not a Saturday, Sunday, or state or federal legal holiday.

IX. Permit Amendments

A. Env-A 612.01, *Administrative Permit Amendments*:

1. An administrative permit amendment includes the following:
   a. Corrects typographical errors;
   b. Requires more frequent monitoring or reporting; or
   c. Allows for a change in ownership or operational control of a source provided that a written agreement containing a specific date for transfer of permit responsibility, coverage, and liability between the current and new permittee has been submitted to the Division.
2. The Owner or Operator may implement the changes addressed in the request for an administrative amendment immediately upon submittal of the request.

B. Env-A 612.03, *Minor Permit Amendments: Temporary Permits and State Permits to Operate*:

1. The Owner or Operator shall submit to the Division a request for a minor permit amendment for any proposed change to any of the conditions contained in this permit which will not result in an increase in the amount of a specific air pollutant currently emitted by the emission units listed in Condition II and will not result in the emission of any air pollutant not emitted by the emission unit.
2. The request for a minor permit amendment shall be in the form of a letter to the Division and shall include the following:
   a. A description of the proposed change; and
   b. A description of any new applicable requirements that will apply if the change occurs.
3. The Owner or Operator may implement the proposed change immediately upon filing a request for the minor permit amendment.

C. Env-A 612.04, *Significant Permit Amendments: Temporary Permits and State Permits to Operate*:

1. The Owner or Operator shall submit a written request for a permit amendment to the Division at least 90 days prior to the implementation of any proposed change to the physical structure or operation of the emission units covered by this permit which increases the amount of a specific air pollutant currently emitted by such emission unit or which results in the emission of any regulated air pollutant currently not emitted by such emission unit.
2. A request for a significant permit amendment shall include the following:
   a. A complete application form, as described in Env-A 1703 through Env-A 1708, as applicable;
   b. A description of:
      i. The proposed change;
      ii. The emissions resulting from the change; and
      iii. Any new applicable requirements that will apply if the change occurs; and
      iv. Where air pollution dispersion modeling is required for a device pursuant to Env-A 606.02, the information required pursuant to Env-A 606.03.
3. The Owner or Operator shall not implement the proposed change until the Division issues the amended permit.

X. Emission-Based Fee Requirements

A. Env-A 705.01, *Emission-based Fees*: The Owner or Operator shall pay to the Division each year an emission-based fee for emissions from the emission units listed in Condition II.

B. Env-A 705.02, *Determination of Actual Emissions for use in Calculating of Emission-based Fees*: The Owner or Operator shall determine the total actual annual emissions from the emission units listed in Condition II for each calendar year in accordance with the methods specified in Env-A 616, *Determination of Actual Emissions*. If the emissions are determined to be less than one ton, the emission-based fee shall be calculated using an emission-based multiplier of one ton.

C. Env-A 705.03, *Calculation of Emission-based Fees*: The Owner or Operator shall calculate the annual emission-based fee for each calendar year in accordance with the procedures specified in Env-A 705.03 and the following equation:

$$FEE = E * DPT$$

where:

FEE = The annual emission-based fee for each calendar year as specified in Env-A 705;
E = Total actual emissions as determined pursuant to Condition X.B; and
DPT = The dollar per ton fee the Division has specified in Env-A 705.03(e).

D. Env-A 705.04, *Payment of Emission-based Fee*: The Owner or Operator shall submit, to the Division, payment of the emission-based fee by April 15th for emissions during the previous calendar year. For example, the fees for calendar year 2008 shall be submitted on or before April 15, 2009.

	PERMIT APPLICATION REVIEW SUMMARY	New Hampshire Department of Environmental Services Air Resources Division P.O. Box 95, 29 Hazen Drive Concord, NH 03302-0095 Phone: 603-271-1370 Fax: 603-271-7053

Facility: **Site Owner:** **Parent Company:**	Concord Expansion Compressor Station (CECS) Tennessee Gas Pipeline Corporation (TGP) El Paso Corporation			**Engineer:**	Muriel Lajoie
Location:	Mammoth Road, Pelham, NH 03076				
AFS #:	3301191266	**Application #:**	08-0023	**Date:**	7/22/2008 ·

APPLICATION & OTHER COMMUNICATION:

Date	Description
1/31/2008	Application received
2/29/2008	Completeness letter sent (Temporary Permit – Shield does not apply)
5/27/2008	Air dispersion modeling review completed
7/11/2008	Request from source to modify Table 4, Item 7.

PROJECT DESCRIPTION/PERMIT HISTORY

This is a new facility. An application for a Temporary Permit for a single new, natural gas-fired, low-NOx Solar Centaur compressor turbine rated at 6,130 hp (58.4 MMBtu/hr gross heat input)[1] and a natural gas-fired emergency generator rated at 425 hp, was filed by Eastern Pipelines Environmental on behalf of TGP.

FACILITY DESCRIPTION

The purpose of the facility is to maintain pressure in the pipeline, through the use of a centrifugal compressor driven by a natural gas-fired turbine. Compressor Station 270B1 is part of the Concord Expansion Project to support growth needs in NH.

PROCESS/DEVICE DESCRIPTION

The following table details the permit required (*) and non-permit required fuel burning devices:

Device	Mfg.	Model #	Serial #	Installation Date	Nameplate Rating	Fuel Type	Max. Fuel Flow Rate (cf/hr)
Compressor Turbine #1*	Solar	Centaur 50-6200LS	TBD	est. 2008	6,346 hp @ 40F 58.4 MMBtu/hr	natural gas	56,000 @ 40F
Emergency Generator *	TBD	TBD	TBD	est. 2008	425 hp	natural gas	4,500 @ 40F
Fuel Gas Heater	TBD	TBD	TBD	TBD	1.5 MMBtu/hr	natural gas	1,597 @ 40F
Space Heater(s)	TBD	TBD	TBD	TBD	1.5 MMBtu/hr	natural gas	1,597 @ 40F
Water Heater	TBD	TBD	TBD	TBD	1.0 MMBtu/hr	natural gas	1,065 @ 40F

POLLUTION CONTROL EQUIPMENT

There is no add-on pollution control equipment on any of the devices.

EMISSION CALCULATIONS

40 CFR 60.4330(a)(2) requires that the Facility "must not burn in the subject stationary combustion turbine any fuel which contains total potential sulfur emissions in excess of 26 ng SO_2/J (**0.060 lb SO_2/MMBtu**) heat input." Env-A 1605.01 requires a sulfur content of gaseous fuel **<15 grains/100 scf**. The following compares the two limits and determines that

[1] Nameplate Ratings based on high heating value (HHV) of natural gas (1042.5 Btu/scf) and maximum fuel flow rate provided in permit application 08-0023.

Env-A 1605.01 is more stringent and will be included as the sulfur limit in the permit.

Assumptions:

0.060 lb SO_2/MMBtu
58.4 MMBtu/hr GHI Combustion Turbine equivalent to 56,000 scf gas/hr
1 grain = 1.43 E-4 lb

0.060 lb SO_2/MMBtu * 58.4 MMBtu/hr = 3.5 lb SO_2/hr / 56,000 scf/hr = 6.26 E-5 lb SO_2/scf

6.26 E-5 lb SO_2/scf / 1.43 E-4 lb/grain = 0.437 grains SO_2/scf or **43.7 grains SO_2/100scf**

Refer to Concord Expansion Compressor Station emissions calculations found at: Conc_Exp_Calculations.xls and summarized below[2]:

	Potential to Emit Summary (tons/year)				
	NOx	**CO**	**VOC**	**PM_{10}**	**SO_2**
Compressor Turbine	23.52	28.64	1.6365	1.68765	15.34226
Emergency Generator	0.47	0.94	0.2338	0.01170	0.00069
Fuel Gas Heater	0.35	0.59	0.0385	0.05316	0.31477
Space Heater(s)	0.35	0.59	0.0385	0.05316	0.31477
Water Heater	0.23	0.39	0.0257	0.03545	0.20991
Total Emissions	**24.69**	**30.75**	**1.95**	**1.81**	**15.97**

STACK INFORMATION

Refer to Modeling Project Summary dated 5/27/2008.

MODELING

The Facility submitted an air quality impact analysis with permit application 08-0023, to assess the Project's maximum predicted ground level pollutant concentrations against applicable National Ambient Air Quality Standards (NAAQS), EPA Significant Impact Levels and Prevention of Significant Deterioration (PSD) increments. A modeling memo dated 3/7/2008 was prepared referencing Section 4 of the permit application.[3]

Results summarized in a TSB modeling memo dated 5/27/2008 stated "...all of the maximum predicted impacts associated with the proposed turbine are below the significant impact levels. Therefore, by definition, the maximum impacts from the Concord Expansion Project will also meet Class II increments and AAQS."

EMISSION TESTING

Emissions testing is being required to verify manufacturer's guarantees of emissions.

SITE VISITS/INSPECTIONS

None

[2] The facility's PTE for NOx, CO, VOC, PM10 and SO2 are less than 50 tons per year for each pollutant and less than 10 tons per year of HAPs. Therefore, the facility is a true minor source.

[3] However, the higher SO_2 emission rate from 40 CFR 60 Subpart KKKK was included in the requested modeling memo to the Technical Services Bureau.

REPORTS/FEES
Permit and modeling review fees were received on 1/31/2008.

CHANGES FROM PREVIOUS PERMIT
This is a new source.

REVIEW OF REGULATIONS
State Regulations

Env-A 600 – *Permitting*
- 606.02 (a) – Applicable – Air dispersion modeling analysis is required because the facility is a new stationary source.
- 607.01(a) – Applicable – The compressor turbine burns natural gas and has a design rating of greater than 10 MMBtu/hr.
- 607.01(d)(2)– Applicable – The emergency generator burns natural gas and has a design rating of less than 10 MMBtu/hr. However, combined with the turbine, their gross heat input is >10 MMBtu/hr, requiring both devices to have a permit.
- 607.01(n) – Not Applicable – The facility is a true minor source of NOx, CO, SO_2, PM10 and VOCs.
- 607.01 (q) – Applicable – The facility is subject to NSPS 40 CFR 60, Subpart KKKK for the compressor turbine and Subpart JJJJ for the emergency generator.
- 607.01(r) – Not Applicable – The facility is not subject to NESHAP Standards because the facility emits less than 10/25 tpy of HAPs.

Env-A 1200 – *Prevention, Abatement and Control of Stationary Source Air Pollution*
- 1211.01 - Not Applicable – The facility has a Potential to Emit of less than 50 tpy of NOx.

Env-A 1400 – *Regulated Toxic Air Pollutants*
- 1402.01 – Not applicable to sources burning virgin fuel.

Env-A 1600 – *Fuel Specifications*
- 1605.01 – Applicable – The sulfur limit for natural gas is 15 grains/100 cf at standard temperature and pressure. NHDES is more stringent than NSPS (20 grains/100 cf).

Env-A 2000 – *Fuel Burning Devices*
- 2002.02 – Applicable – visible emissions from the compressor turbine and the emergency generator are limited to 20%.
- 2002.04 – Not Applicable – The compressor turbine and emergency generator are not steam generating units.
- 2002.08 – Applicable – TSP emissions from the compressor turbine are limited to 0.30 lb/MMBtu

Federal Regulations
- 40 CFR 60 Subpart KKKK – Applicable - New combustion turbine with a heat input rate greater than 10 MMBtu/hr constructed after February 18, 2005.
- 40 CFR 60 Subpart JJJJ – Applicable - Emission limitations for owners and operators of stationary emergency engines greater than or equal to 130 hp, manufactured after January 1, 2009. The source intends to purchase an engine manufactured after this date, therefore is subject to this NSPS.
- 40 CFR 63 Subpart YYYY– Not Applicable - The facility is not subject to this NESHAP because the potential to emit HAPs is less than the major source thresholds of 10/25 tpy.
- 40 CFR 63 Subpart ZZZZ – Applicable – The facility is subject to this NESHAP because it is an area source of HAP emissions. The facility meets the requirements of Subpart ZZZZ by complying with the NSPS under 40 CFR

60 Subpart JJJJ.

- 40 CFR 93, Subpart B – *Determining Conformity of General Federal Actions to State or Federal Implementation Plans* - Applicable - For certain Federal actions, a conformity determination is required for each pollutant where the total of direct and indirect emissions in a non-attainment or maintenance area caused by a Federal action would equal or exceed specific levels. The pollutants requiring a review in Hillsborough and Rockingham County ozone non-attainment areas are VOCs and NOx. The summary found in Permit Application 08-0023, Appendix K shows the project to be in conformity with the respective levels.

PUBLIC COMMENT PERIOD (7/10/2008-8/11/2008)

In two emails dated July 11 and 22, 2008, Trinh Tran of Tennessee Gas Pipeline requested three changes as noted below:

TGP 1) "Item 7 refers to Method of Compliance for NOx and I would ask for 1) Method 9 to be removed as this method is for opacity only. NSPS Subpart A requires demonstration to an *applicable* opacity standard as specified in the applicable source category subpart, i.e., subpart KKKK. However, as Subpart KKKK does not regulate opacity for turbines, there is no opacity standard in this subpart. Also, the subject unit fire only natural gas with negligible PM emissions. Additionally, I trust that opacity monitoring requirement for the turbine (EU01) is satisfied via Item 3 of Table 3;"

DES 1) As there is no opacity requirement in 40 CFR 60, Subpart KKKK and Table 3., Item 3. requires the testing of opacity from EU01 "upon request by the Division", Table 4., Item 7.e. will be removed and the section re-lettered as 7.a. through 7.d.

TGP 2) "Application of Method 19, in lieu of Methods 2, 2C, 2F, 2G, or 2H (item 7b) to calculate exhaust flow. As stated under §60.4400(a)(1)(ii) which I have copied below from NSPS Subpart KKKK, Method 19 is an approved method to calculate the NOx emission rate in lb/MMBtu."

> *<u>§60.4400(a)(1)(ii)</u> Measure the NOx and diluent gas concentrations, using either EPA Methods 7E and 3A, or EPA Method 20 in appendix A of this part. Concurrently measure the heat input to the unit, using a fuel flowmeter (or flowmeters), and measure the electrical and thermal output of the unit. Use EPA Method 19 in appendix A of this part to calculate the NOx emission rate in lb/MMBtu. Then, use Equations 1 and, if necessary, 2 and 3 in §60.4350(f) to calculate the NOx emission rate in lb/MWh.*

DES 2) Though the leading statement in Table 4., Item 7. states that "Division approved alternatives" shall be used, the NSPS standard clearly indicates that calculation of the stack flow (via Method 19)in lieu of the stated measurement methods is approved. Therefore, Item 7.b. will be revised to remove listed methods and add Method 19.

TGP 3) "I would ask is the deletion of Method 4 if we are allowed to conduct Method 19. Method 4 is for the determination of water vapor in the stack gases and with Method 19, since all emissions will be on a dry basis and a dry F-factor (Fd) will be utilized, this renders Method 4 unnecessary."

DES 3) Table 4, Item 7.d. has been removed as the emissions will be calculated on a dry weight basis.

DES 4) Additional changes have been made to Table 4., Items 7a. and 7b.to clarify units of measure.

SUMMARY AND CONCLUSIONS

The facility is a true minor source of air pollution and will be able to comply with all regulations. A Temporary Permit will be drafted.

Facility Name:	Concord Expansion Compressor Station	**Application No.**	08-0023	**Permit No.:**	TP-B-0544
Facility Address:	Mammoth Road, Pelham, NH 03076	**Facility Contact:**	Trinh Tran	**Issued:**	8/15/2008
Facility ID:	3300900115	**Telephone No.:**	713-420-7931	**Expires:**	2/28/2010
Owner Name:	Tennessee Gas Pipline Company			**Calcs Date:**	03/14/08
Parent Company:	El Paso Corporation				

					Nameplate Rating			
Device	**Manufacturer**	**Model #**	**Serial #**	**Installation Date**	**hp**	**MMBtu/hr[6]**	**Fuel Type**	**Max. Fuel Flow Rate @ 40[F] (mmcf/hr)**
Compressor Turbine #1	Solar	Centaur 50-6200LS	TBD	TBD	6346	58.4	Natural Gas (LNG)	0.056000
Emergency Generator	TBD	TBD	TBD	TBD	425	4.68	LNG	0.004489
Fuel Gas Heater	TBD	TBD	TBD	TBD	N/A	1.66	LNG	0.0016
Space Heater(s)[9]	TBD	TBD	TBD	TBD	N/A	1.66	LNG	0.0016
Water Heater	TBD	TBD	TBD	TBD	N/A	1.11	LNG	0.0011

			Maximum Load	
Device	**Pollutants**	**Emissions Factors (lb/MMBtu, HHV)[1,2]**	**Hourly Emissions @ 40[F] (lb/hr)**	**Potential to Emit (tpy)[7]**
Compressor Turbine	NOx	0.092	5.37	23.52
	CO	0.112	6.54	28.64
	UHC[3], Emissions as VOC	0.0064	0.37	1.64
	PM_{10}	0.0066	0.39	1.69
	SO_2	0.06	3.50	15.34
	HAP	0.00305	0.18	0.78

				Maximum Load	
Device	**Pollutants**	**Emissions Factor[4]**	**Units**	**Hourly Emissions @ 40[F] (lb/hr)**	**Potential to Emit (tpy)[7]**
Emergency Generator	NOx	2.00	g/bhp-hr	1.87	0.47
	CO	4.00	g/bhp-hr	3.74	0.94
	VOC	1.00	g/bhp-hr	0.94	0.23
	PM_{10}	0.010	lb/MMBtu	0.047	0.012
	SO_2	0.000588	lb/MMBtu	0.0028	0.00069

	Potential to Emit Summary (tons/year)				
	NOx	**CO**	**VOC**	**PM_{10}**	**SO_2[8]**
Compressor Turbine	23.52	28.64	1.6365	1.68765	15.34226
Emergency Generator	0.47	0.94	0.2338	0.01170	0.00069
Fuel Gas Heater[5]	0.35	0.59	0.0385	0.05316	0.31477
Space Heater(s)[5]	0.35	0.59	0.0385	0.05316	0.31477
Water Heater[5]	0.23	0.39	0.0257	0.03545	0.20991
Total Emissions	**24.69**	**30.75**	**1.95**	**1.81**	**15.97**

[1] Compressor Turbine NOx, CO and UHC Vendor Guaranteed emissions from Permit Application 08-0023, Section 2.1.1 *Typical Operations* are the basis for these emissions factors. They are the same emissions factors required by 40 CFR 60, Subpart KKKK. Subpart KKKK also requires an SO2 emission rate of <0.06 lb/MMBtu. The turbine will burn exclusively natural gas, which will ensure compliance with Subpart KKKK. PM10 and HAP emissions factors are from AP-42, Section 3.1 *Stationary Gas Turbines*, Table 3.1-2a.

[2]Example Compressor Turbine emission factor calculation for CO:

EFx = (Cd x Fd)* [20.9]/[20.9 - %O2]

CO lb/MMBtu = (50 ppm(vol) * 28 gmw / 385.1E6) * 8710 dscf/MMBtu * [20.9/ 20.9-15]

CO = 0.112 lb/MMBtu

[3]Compressor turbine VOC emissions are assumed to be 20% of Unburned Hydrocarbon (UHC) emissions as specified in Solar Turbines Product Information Letter (PIL) 168.

[4] Emergency Generator NOx, CO and VOC exhaust emission limits are equal to New Source Performance Standards (NSPS) for engines greater than or equal to 130 hp, manufactured after January 1, 2009 as noted in 40 CFR 60, Subpart JJJJ, Table 1.

5 Emissions factors for the Fuel Gas Heater, Space Heater(s) and Water Heater units taken from AP-42, Section 1.4 *Natural Gas Combustion*, Tables 1.4-1 and 1.4-2. Units are < 10 MMBtu and do not require permits per Env-A 607.01(a), but emissions are included for completeness.

[6]The potential fuel heat input for the Combustion Turbine is based on the heating value (HHV) of natural gas: 1042.5 Btu/scf from Permit Application 08-0023, Table B.7.

[7] Compressor Turbine based on 8760 hours per year. Emergency Generator based on 500 hours per year.

[8] Maximum sulfur content for Fuel Gas Heater, Space Heater(s) and Water Heater per Env-A 1605.01(a) = 15 grains/100 cf

[9] The total gross heat input of the space heaters will not exceed 1.66 MMBtu/hr based on the HHV of natural gas.

Facility Name:	Concord Expansion Compressor Station	**Application No.**	08-0023		**Permit No.:**	TP-B-0544
Facility Address:	Mammoth Road, Pelham, NH 03076	**Facility Contact:**	Trinh Tran		**Issued:**	8/15/2008
Facility ID:	3300900115	**Telephone No.:**	713-420-7931		**Expires:**	2/28/2010
Owner Name:	Tennessee Gas Pipline Company				**Calcs Date:**	03/04/08
Parent Company:	El Paso Corporation					

					Nameplate Rating			
Device	**Manufacturer**	**Model #**	**Serial #**	**Installation Date**	**hp**	**MMBtu/hr**[5]	**Fuel Type**	**Max. Fuel Flow Rate (mmcf/hr)**
Compressor Turbine #1	Solar	Centaur 50-6200LS	TBD	TBD	6346	52.6	Natural Gas (LNG)	0.056
Emergency Generator	TBD	TBD	TBD	TBD	425	4.7	LNG	0.0050
Fuel Gas Heater	TBD	TBD	TBD	TBD	N/A	1.5	LNG	0.0016
Space Heater(s)	TBD	TBD	TBD	TBD	N/A	1.5	LNG	0.0016
Water Heater	TBD	TBD	TBD	TBD	N/A	1.0	LNG	0.0011

			Maximum Load	
Device	**Pollutants**	**Emissions Factors (lb/MMBtu, HHV)**[1,2,3]	**Hourly Emissions @ 40**^{F} **(lb/hr)**	**Permitted Emissions (tpy)**[6]
Compressor Turbine	NOx	0.092	4.84	21.19
	CO	0.112	5.89	25.80
	UHC[4], Emissions as VOC	0.0064	0.34	1.47
	PM_{10}	0.0066	0.35	1.52
	SO_2	0.0034	0.18	0.78
Emergency Generator	NOx	0.401	1.88	0.47
	CO	0.802	3.75	0.94
	VOC	0.200	0.94	0.23
	PM_{10}	0.010	0.047	0.012
	SO_2	0.000588	0.0028	0.00069

Facility Name:	Concord Expansion Compressor Station	**Application No.**	08-0023	**Permit No.:** TP-B-0544
Facility Address:	Mammoth Road, Pelham, NH 03076	**Facility Contact:**	Trinh Tran	**Issued:** 8/15/2008
Facility ID:	3300900115	**Telephone No.:**	713-420-7931	**Expires:** 2/28/2010
Owner Name:	Tennessee Gas Pipline Company			**Calcs Date:** 03/04/08
Parent Company:	El Paso Corporation			

	Summary (tons/year)				
	NOx	**CO**	**VOC**	**PM_{10}**	**SO_2[8]**
Compressor Turbine	21.19	25.80	1.4743	1.52042	0.78325
Emergency Generator	0.47	0.94	0.2340	0.01170	0.00069
Fuel Gas Heater[7]	0.35	0.59	0.0385	0.05316	0.31477
Space Heater(s)[7]	0.35	0.59	0.0385	0.05316	0.31477
Water Heater[7]	0.23	0.39	0.0257	0.03545	0.20991
Total Emissions	**22.36**	**27.91**	**1.79**	**1.64**	**1.41**

[1] Compressor Turbine NOx, CO and UHC Vendor Guaranteed emissions from Permit Application 08-0023, Section 2.1.1 *Typical Operations* are the basis for these emissions factors. PM10, SO2 and HAP emissions factors from AP-42, Table 3.1-2a. Emission Factors for Criterial Pollutants and Greenhouse Gases from Stationary Gas Turbines

[2]Example Compressor Turbine emission factor calculation for CO:

EFx = (Cd x Fd)* [20.9]/[20.9 - %O2]

CO lb/MMBtu = (50 ppm(vol) * 28 gmw / 385.1E6) * 8710 dscf/MMBtu * [20.9/ 20.9-15]

CO = 0.112 lb/MMBtu

NOx, CO and UHC emissions factors for combustion turbine from Vendor Guarantee. PM10, SO2 and HAP emissions factors from AP-42, Table 3.1-2a. Emission Factors for Criterial Pollutants and Greenhouse Gases from Stationary Gas Turbines

[3] Emergency Generator NOx, CO and VOC exhaust emission limits are equal to New Source Performance Standards (NSPS) for engines greater than or equal to 130 hp, manufactured after January 1, 2009.

[4] VOC emissions are assumed to be 20% of Unburned Hydrocarbon (UHC) emissions

[5] The potential fuel heat input for the Combustion Turbine is based on the heating value (LHV) of natural gas provided by the Facility: 939.2 Btu/scf. Emergency Generator was calculated using a conservative estimate of 11,000 Btu/hp-hr for fuel efficiency from Permit Application 08-0023, Table B.7.

[6] Compressor Turbine based on 8760 hours per year. Emergency Generator based on 500 hours per year.

[7] Fuel Gas Heater, Space Heater and Water Heater emissions factors for these units taken from AP-42, Section 1.4 Natural Gas Combustion, Tables 1.4-1 and 1.4-2. Units are < 10 MMBtu and do not require permits per Env-A 607.01(a), but emissions are included for completeness.

[8] Sulfur content per Env-A 1605.01(a) = 15 grains/100 cf